# TECHNICAL REVIEW DOCUMENT OPERATING PERMIT 000PMR224

to be issued to:

BIV Generation Company, LLC Morgan County Source ID 0870027

Prepared by Jacqueline Joyce
December 2000
Revised June 2001 and February 2002
Revised May 2002 based on comments made during the Public Comment Period
Revised July and August 2002 to Reflect Startup of Combined Cycle Operation, Transfer of Ownership and to Address EPA Comments on Proposed Permit

## I. Purpose:

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted April 27, 2000, additional technical information submitted July 10 and October 5, 2000, comments on the draft permit and technical review document received on December 2001. various telephone conversations 19. and e-mail correspondence with the source and review of Division files. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence.

## II. Source Description:

This facility consists of two combustion turbines used to generate power during peak periods of electrical demand and is defined under Standard Industrial Classification 4911. These combustion turbines are part of the Brush Cogeneration Facility, which consists of five combustion turbines (some operated as cogeneration units and some operated solely to produce power) and three

different operating companies. A separate Operating Permit has been issued for each operating company, however, for permitting purposes the Brush Cogeneration Facility is considered one facility. The BIV Generation Company LLC (BIV) facility consists of two simple cycle combustion turbines operated solely to produce power. The turbines are equipped with water injection systems to control nitrogen oxide emissions. Each turbine serves a generator with a nameplate capacity of 28.5 MW. Recently, each turbine was equipped with a duct burner and a 90 MW steam turbine was added to the facility to allow for combined cycle operation of the units to provide greater electrical capacity. Commercial operation of the combined cycle units commenced on May 1, 2002. As part of the modification to operate the turbines in combined cycle mode, a cooling tower was added to the facility and this unit has also been included in the operating permit. The combustion turbines are referred to as BIV turbine 1, GT-4 or Brush 4A and BIV turbine 2, GT-5 or Brush 4B.

Note that a revised construction permit, issued February 21, 2001, approves the conversion of these two turbines to combined cycle units. Construction on the conversion to combined cycle operation commenced shortly after the permit was issued. The turbines commenced commercial operation of the units as combined cycle units on May 1, 2002.

The facility is located on 90 acres just south of Brush in an area designated as attainment for all criteria pollutants. Although, currently, the BIV turbines produce electricity directly and not through a steam generator, these turbines are located at a facility that includes one of the 28 listed sources (fossil-fuel fired steam electric plant of more than 250 million Btu per hour) and therefore, the major stationary source threshold is 100 tons/yr. This source is considered to be a major stationary source (Potential to Emit > 100 tons/year) in an attainment area and has a PSD permit. Future modifications to this facility which are in excess of significance levels as defined in Colorado Regulation No. 3, Part A, Section I.B.58, would result in a major modification and the application of PSD requirements. The BIV turbines are considered to be a single stationary source, along with the Brush Cogeneration Partnership (BCP) turbine (Brush 2) and the Colorado Power Partnership (CPP) turbines (Brush 1 and 3), although separate operating permits will be issued to BCP and CPP. Facility wide emissions (includes CPP, BIV and BCP) and BIV only emissions are as follows:

Pollutant	Facility	BIV Potential		
	Potential to	to Emit <sup>1</sup>		
	Emit <sup>1</sup>	(tons/yr)		
	(tons/yr)			
PM	73.48	16.59		
PM <sub>10</sub>	73.48	16.59		
NO <sub>X</sub>	341.7	83.3		
	318.4	60		
SO <sub>2</sub>	4.79	2.79		

Pollutant	Facility	BIV Potential	
	Potential to	to Emit <sup>1</sup>	
	Emit <sup>1</sup>	(tons/yr)	
	(tons/yr)		
CO	386.1	156	
	350.1	120	
VOC	73.58	22.38	

Values in bold italics is potential to emit after combined cycle operation of the turbines commence. Note that the increase in PM and PM<sub>10</sub> emissions is due to the addition of a cooling tower to support combined cycle operation

Potential to Emit is based on permitted emission limits. The Division's emission inventory indicates that BIV typically reports and pays fees on potential emissions, which is an acceptable practice, and therefore no actual emission data is available.

There are no Federal Class I designated areas within 100 kilometers and no affected states within 50 miles of this facility.

This facility certified within the Title V permit application they are not subject to 112(r), the Accidental Release Requirements.

#### III. Emission Sources:

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site:

<u>Units S004 and S005</u> - Two (2) Westinghouse Model 251AA Natural Gas Fired Combustion Turbines, each Rated at 420 mmBtu/hr, Serial Numbers: 17A301 (GT-4) and 17A302 (GT-5). Each turbine is equipped with water injection to control  $NO_X$  emissions. <u>Recently</u>, each unit was equipped with one (1) VOGT-NEM, natural gas fired duct burner rated at 300 mmBtu/hr and steam can be routed through a 90 MW General Electric condensing stream turbine generator to provide additional electrical capacity.

#### Discussion:

1. Applicable Requirements - The units above began operating in July 1999 as simple cycle units. These units were issued Colorado Construction Permit 98MR0727 PSD (initial approval) on May 25, 1999. A revised construction permit was issued on February 21, 2001 to convert these simple cycle units to combined cycle units. The application for this permit indicated that the turbines would not start up in combined cycle mode until June 2002. Construction on the conversion to combined cycle operation began shortly after the revised permit was issued. Commercial operation of the units in combined cycle mode began on May 1, 2002.

The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the initial approval construction permit

(98MR0727 PSD, issued February 21, 2001) was issued and/or the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification for construction permit 98MR0727 PSD and the appropriate provisions of the construction permit have been directly incorporated into this operating permit. It should be noted that since operation of the units in combined cycle mode began May 1, 2002, the semi-annual monitoring and deviation reporting and annual compliance certification requirements shall serve as the self-certification that these units can comply with the conditions in the permit. The following applicable requirements from construction permit 98MR0727 PSD have been identified for these units:

 Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on August 21, 2002 (condition 2).

This requirement for construction applies to the addition of the duct burners and steam turbine to allow for combined cycle operation of the turbines. As previously stated, construction commenced shortly after the revised construction permit was issued, therefore this requirement will not be included in the operating permit.

• The permittee shall not commence operation of this modification without giving notice to the Division thirty (30) calendar days prior to the date on which commencement will take place.

This condition only applies to startup of the units in combined cycle mode. The source submitted a start-up notice on January 14, 2002, indicating that commercial operation would commence on April 1, 2002. Commercial operation of these units began on May 1, 2002. Since the requirement to submit the startup notice has been fulfilled and since the units have commenced commercial operation, this requirement will not be included in the operating permit.

 Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (condition 3).

The due date of the first semi-annual monitoring report required by the operating permit will suffice as the self-certification that these units, operated in simple cycle mode, comply with the applicable requirements in the construction permit. Since these units will begin operation, in combined cycle mode, shortly before issuance of the operating permit, this condition will be included in the permit. Note that, since the source has requested that the annual compliance period end on March 31, 2002, the first semi-annual monitoring period ends less than 180 days after startup of the units in combined cycle mode. Therefore, the first annual

compliance certification submitted after these units commence operation in combined cycle mode will serve as the self-certification that these units can comply with the permit conditions.

 Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 5 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation". The 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

 This source is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for control of Oxides of Nitrogen (NO<sub>X</sub>) and Carbon Monoxide (CO) (condition 6).

## NO<sub>X</sub>:

- water injection has been determined to be BACT for these turbines.
- o NO<sub>X</sub> emissions shall not exceed 30 ppmvd at 15% O<sub>2</sub>, on an hourly average until June 30, 2001.
- o NO<sub>X</sub> emissions beginning July 1, 2001 and thereafter shall not exceed 25 ppmvd at 15% O<sub>2</sub>, on an hourly average.

Note that the  $NO_X$  BACT limit that is effective until June 30, 2001 has not been included in the permit since it is no longer applies.

- o This conditional BACT is being determined considering, the urgency of augmenting power generation capacity prior to the peak demand seasons, the turbines will be operated for limited durations for peaking duty, and the permittee's commitment to reduce emissions from the existing turbines. The operation schedule (hours of operation per year) will not increase.
- o Modification of the permit (or issuance of a new permit) for any future increase in operation of the emission sources covered under this permit will require application of Best Available Control Technology at the time of such application for modification (or issuance of new permit).

The above two requirements were included in the construction permit. During the public comment period for the modification of the construction permit, it became apparent that the language in the permit did not reflect what the EPA or the Division had intended. EPA submitted comments on the draft permit on January 24, 2001. In a follow-up letter (see attached) received February 22, 2001 regarding the permit, EPA clarified the intent of the above two conditions in the permit. In this letter, EPA indicated that "Any future changes at this facility that involve Units 4A and 4B will involve a renewed analysis of BACT." This language was not included in the construction permit but was included in the draft operating permit. However, in their comments on the draft operating permit received during the public comment period, the source objected to the Division including this language in the operating permit. The Division agrees that the language in EPA's letter is not an applicable requirement and should not be included in the operating permit. However, because EPA's February 22, 2001 letter provides guidance on how future modifications to the turbines at this facility should be processed the language in the letter is being discussed and attached to the technical review document for future reference should any modifications be made to the facility in the future.

 Total operating hours for both turbines together shall not exceed 4,000 turbine hours/yr.

#### CO:

- Good combustion practices has been determined to be BACT for these turbines.
- o CO emissions shall not exceed 60 ppmvd at 15% O<sub>2</sub>, on an hourly average.

The source has indicated that they cannot meet the BACT limits provided in the permit during periods of startup, shutdown and partial load. EPA guidance (John B. Rasnic to Linda M. Murphy, dated January 28, 1993, "Automatic or Blanket Exemptions for Excess Emissions during Startup and Shutdowns Under PSD") states that "... PSD permits cannot contain automatic exemptions which allow excess emissions during startup and shutdown....the exemptions granted under some New Source Performance Standards (NSPS) are not applicable to this issue under PSD. The NSPS are technology based standards that are not directly required for meeting ambient standards." Furthermore EPA guidance (Kathleen M. Bennett to Regional Administrators, dated February 15, 1983, "Policy on Excess Emissions During Startups, Shutdowns, Maintenance and Malfunction") indicates that "...startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods."

The January 28, 1993 EPA memo addresses using alternate limitations during startup and shutdown and although they do not necessarily approve this method, they point out that these types of standards need to have clear definitions and limits and that the standard should demonstrate compliance with the short term PSD increments and ambient air standards, as well as the long term ambient air standards. The Division has opted to take the approach to provide an alternate BACT limit during periods of startup and shutdown when the source indicates that they cannot meet the BACT limits in their permits during these periods. In order to provide an alternate BACT limit during startup and shutdown, the source must demonstrate that with this alternate BACT limit, compliance with the short and long term NAAQS and PSD increments can be maintained. The source submitted modeling on July 10, 2000 demonstrating that with their requested alternate BACT limits for startup and shutdown that there are no significant impacts to the NAAQS or PSD increments. The source requested the following alternate BACT limits in their Title V operating permit application submitted April 27, 2000. The requested BACT limits were the same as requested for the CPP turbines in a March 31, 2000 request for those units. The requested BACT limits are as follows:

Startup  $NO_X$  60 ppmvd @ 15%  $O_2$  CO 360 ppmvd @ 15%  $O_2$  Shutdown  $NO_X$  60 ppmvd @ 15%  $O_2$  CO 350 ppmvd @ 15%  $O_2$ 

At the request of the Division, the source submitted continuous emission monitoring data from several startups and shutdowns on October 5, 2000. The Division reviewed the data and calculated average emissions for the event, for a partial hour (averaged over a period less than one hour and typically only includes either startup or shutdown data) and for a full hour (most likely includes some "normal" data). A review of this data indicates that the source's requested alternate BACT limits are typically higher than the actual data for a full hour and there were limited instances where the requested BACT limit was exceeded for a partial hour. Since data from only a few startups and shutdowns was available and since there is no data from combined cycle operation of the BIV turbines, the Division will include the alternate BACT limits as requested.

Note that startup and shutdown are defined as follows:

"Startup" means the setting in operation of any air pollution source for any purpose. Setting in operation for these turbines begins when fuel is injected into the gas turbine and ends when gross power output from the gas turbine first reaches or exceeds 10 MW.

"Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for these turbines begins when the order to shutdown is sent and gross power output from the gas turbine is equal to 10 MW or less and ends when emissions cease.

- "Good Combustion Practices" constitute monitoring and control of several operating parameters. These parameters include, but are not limited to, fuel flow rate, primary and secondary air flows, carbon monoxide concentration in the flue gas, level of excess air, and recirculating air flow. All relevant parameters and their optimal operating ranges shall be identified and included in the required operation and maintenance plan (condition 7).
- Within 90 days of startup, a continuous emission monitoring (CEM) system shall be installed, calibrated, certified and operated on the exhaust stack to determine and record (condition 8):
  - o Exhaust gas flow rate
  - o Moisture content
  - Concentration of Oxides of Nitrogen, ppmvd @ 15% O<sub>2</sub>
  - o Emissions of Oxides of Nitrogen, tons/month
  - o Concentration of Carbon Monoxide, ppmvd @ 15% O<sub>2</sub>
  - o Emissions of Carbon Monoxide, tons/month
  - o Load at which both the turbine and the duct burner are operating
- Exhaust flow rates, and moisture content of exhaust gases may be parametrically monitored. Procedure and accuracy of the continuous emission monitoring systems shall conform to 40 CFR Part 60, Appendix F (condition 8).
- Note that the requirement to continuously monitor NO<sub>X</sub> emissions, as set forth in Condition 8 above, will be satisfied with a NO<sub>X</sub> continuous emission monitoring system that meets the requirements of 40 CFR Part 75 (condition 8).
- The Division may take direct enforcement action based solely on continuous emission monitor data if the data shows any excursion above the Oxides of Nitrogen or Carbon Monoxide limitations determined as BACT (condition 8).
- The turbines are subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart GG - Standards of Performance for Stationary Gas Turbines (condition 10):
  - o  $NO_X \le 75$  ppmvd at 15% oxygen. (Compliance with the BACT limits will satisfy this NSPS standard).
  - o  $SO_2 \le 150$  ppmvd at 15% oxygen.
  - o Fuel consumption shall be continuously monitored and recorded
  - Sulfur and nitrogen content of the fuel being fired in the turbines shall be monitored as specified in this Subpart GG

The above requirements were specifically identified in construction permit 98MR0727 PSD, however some clarification is required. The construction permit indicates that fuel consumption shall be continuously monitored. Actually, this requirement is to install and operate a continuous monitoring

system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine (§ 60.334(a)). NSPS GG requires that this system shall be accurate to within  $\pm$  5 percent. The sulfur and nitrogen content of the fuel shall be monitored on a daily basis (40 CFR Part 60 Subpart GG § 60.334(b)(2)).

Although not specifically included in the construction permit, the following requirements also apply:

- o Exemptions from the  $NO_X$  limits, under certain special conditions, provided in 40 CFR Part 60 §§ 60.332(f) & (i).
- No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight (§ 60.333(b))
- o Excess emissions reporting requirements (§ 60.334(c))
- o Performance test requirements, regarding fuel sampling (§§ 60.335(d) & (e))
- The duct burners are subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units (condition 10):
  - Particulate matter emissions shall not exceed 0.03 lbs/mmBtu (§ 60.42a(a)(1))
  - Opacity of emissions shall not exceed 20% opacity (6-minute averages), except for one six-minute period not to exceed 27% (§ 60.42a(b))
  - o  $NO_X$  emissions shall not exceed 1.6 lbs/MW-hr gross energy output, on a 30-day rolling average (§ 60.44a(d)(1))
  - o SO<sub>2</sub> emissions shall not exceed 0.20 lbs/mmBtu, on a 30-day rolling average (§ 60.43a(b)(2))

Note that 40 CFR Part 60 Subpart Da § 60.43a(b)(2) specifically states that the SO<sub>2</sub> limitation is "100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.2 lbs/mmBtu". Since these units burn natural gas, emissions will be below 0.2 lbs/mmBtu (40 CFR Part 75, Appendix D allows sources burning pipeline quality natural gas to use a default emission factor of 0.0006 lbs/mmBtu). Because emissions are below 0.2 lbs/mmBtu the source may emit 100% of the potential combustion concentration, i.e. no limits. However, since this "no SO<sub>2</sub> limits" only applies if emissions are below 0.2 lbs/mmBtu, the Division included the upper bound of 0.2 lbs/mmBtu as the emission limitation.

- o Compliance with the NSPS requirements shall be monitored in accordance with the requirements in 60.46a and 60.47a, including but not limited to the following:
  - Calculate NO<sub>X</sub> emissions in accordance with the requirements in § 60.46a(i)

- Install and operate a continuous emission monitor for NO<sub>X</sub> and either CO<sub>2</sub> or O<sub>2</sub> (§§ 60.47a(c) & (d))
- Install and operate a wattmeter (§ 60.47a(k))

Note that the construction permit indicates that only a wattmeter is required, however, § 60.47a(k) identifies procedures to be used to determine gross output for sources demonstrating compliance with the output-based NO<sub>X</sub> standard. This section requires certain equipment to be installed to monitor the steam output for units that generate process steam. Since BIV supplies process steam, then additional monitoring is required to demonstrate compliance with the NSPS NO<sub>X</sub> limit and those requirements will be included in the permit.

 Install and operate a continuous flow monitor system (§60.47a(I))

Recently, EPA made revisions, effective June 11, 2001, to NSPS Subpart Da in order to more appropriately address duct burners. These revisions provided two methods for combined cycle units (turbine plus duct burner) to demonstrate compliance with the NO<sub>X</sub> emission limits and specified that owners or operators of duct burners are not required to install the continuous monitoring systems for NO<sub>X</sub> emissions, watts and steam characteristics. Owners or operators of combined cycle units may demonstrate compliance with the NO<sub>x</sub> emission limits by either conducting a stack test (3 one-hour tests) or using NO<sub>X</sub> continuous emission monitors. The source has not indicated during review of the permit during a pre-public comment review period and the official public comment period that they would prefer to conduct the stack test. Therefore, the Division has written the permit to require the source to use the NO<sub>x</sub> continuous emission monitoring system to monitor compliance with the NO<sub>X</sub> emission limits. Note that rather than calculating NO<sub>X</sub> emissions in accordance with § 60.46a(i), as indicated in the construction permit, the source will be required to calculate emissions in accordance with the requirements in §§ 60.46a(k)(2) & (3).

In addition, although NSPS Subpart Da § 60.47a(c)(2) specifies that a Part 75 monitor may be used to meet the  $NO_X$  continuous emission monitoring requirements, it includes certain stipulations (i.e. data used for reporting shall not be biased and shall not include replaced data) when Part 75 monitors are used. Originally, the Division considered that since the revisions to the NSPS specify that duct burners are not required to be equipped with continuous emission monitors for  $NO_X$ , the Division believed that these special provisions for using a Part 75 monitor would not apply. However, during EPA's 45-day review period, the EPA indicated that if the

source opted to use their CEMS to monitor compliance with the  $NO_X$  limits, rather than conduct the stack test, that all the CEMS requirements identified in NSPS Subpart Da would apply to the duct burner CEMS systems. Therefore, the permit includes the certain stipulations for using the Part 75 monitor.

NSPS Subpart Da contains requirements on the minimum quantity of quality assured data that must be obtained from the continuous emission monitoring system and provisions to replace data if the minimum is not met. The minimum data requirement is to obtain 18 hours of data in at least 22 of 30 successive boiler operating days. Again, the Division believed that, with the changes made to NSPS Subpart Da, that the minimum data and corresponding data replacement requirements would not apply to the BIV duct burners because the revisions made to the NSPS specified that a continuous emission monitor is not required for duct burners. Again, EPA indicated during their 45-day review period, that if the source elected to use their CEMS to monitor compliance with the NSPS Da NO<sub>x</sub> limits, all of the NO<sub>x</sub> CEMS requirements in NSPS Da would apply. Therefore, the permit includes the minimum data requirements and the provisions to replace data if the minimum data requirements are not met.

o Performance tests shall be conducted in accordance with the requirements in § 60.48a(f).

Note that the Division is only requiring a stack test for PM. A performance test for  $NO_X$  will be conducted using the  $NO_X$  CEMS. A performance test for  $SO_2$  will not be required because compliance with the units burn natural gas as fuel so a compliance test for  $SO_2$  is not necessary.

o Reporting requirements in § 60.49a

Reporting requirements include the requirement to submit the results of the performance test and evaluation of the continuous emission monitor, in addition to reporting continuous emission monitoring data, minimum data and data replacement requirements.

- The turbines and duct burners are also subject to the requirements in 40 CFR Part 60 Subpart A New Source Performance Standards General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A, the following will be included in the permit (condition 10):
  - o Good practices (§ 60.11(d))
  - o Circumvention (§ 60.12)

Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these

requirements, if still applicable, will be included in the permit as periodic monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

In addition, the permit included the requirement for excess emission reports (40 CFR Part 60 Subpart A § 60.7(c)). The NSPS specifies that these reports shall be submitted semi-annually, except when more frequent reporting is required by the applicable subpart or if the Division determines that more frequent reporting is necessary to accurately assess the compliance status of the emission unit. The Division has determined that more frequent reporting is necessary and therefore, excess emission reports shall be submitted quarterly.

- The source is subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, D – Standard for Sulfur Dioxide, 3 – Combustion Turbines (condition 11). These are state-only requirements.
  - o SO<sub>2</sub> emissions shall not exceed 0.35 lbs/mmBtu.
  - o Opacity of emissions shall not exceed 20%
- Particulate matter emissions from each turbine or turbine and duct burner combination shall not exceed the limitations in Reg 1, Section III.A.1.b (condition 12).
- This source is subject to the odor requirements of Regulation No. 2 (condition 13)

Turbines, with or without duct burners, are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section V) of the permit.

- An annual report shall be submitted to the Division, by April 30, for the previous calendar year. This report shall contain, at a minimum, the following (condition 15):
  - o Consumption of natural gas
  - o Operating loads, and hours of operation at each load
  - o Total emissions of all pollutants as determined by the CEMS
  - o Episodes of emission exceedances
  - o Certification of compliance/non-compliance of permit conditions
  - Status of improvements to further reduce emissions of Oxides of Nitrogen
  - o Upset conditions and remedial measures taken

With the issuance of the operating permit the source will be required to certify annually that they are in compliance with the conditions in the operating permit, which includes compliance with the emission limitations, fuel consumption limits and reporting requirements (including APEN

reporting and excess emission reports). The majority of the information that the source is required to include in this annual report is already required to be reported under APEN (fuel consumption and annual emissions) and excess emission reporting requirements. Therefore, this requirement will not be included in the operating permit.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request (condition 16).
  - o Consumption of natural gas for combustion in the two turbines and duct burners, together, shall not exceed 1,618.3 mmSCF/yr.
  - o Upon startup of the turbines in combined cycle operation, the following short-term consumption limits apply:

June – August: 1,213.725 mmSCF/yr
 Sept – Nov 647.32 mmSCF/yr
 Dec – Feb 1,213.725 mmSCF/yr
 Mar – May 647.32 mmSCF/yr

The gas throughput limit in the construction permit was increased to accommodate the operation of the duct burners. Typically the Division includes short term fuel consumption limitations on new sources to verify that these new sources can comply with the limitations. The turbines themselves (simple cycle operation) were subject to lower gas consumption limits in the previous version of the construction permit and have demonstrated compliance with those limits, therefore, in the construction permit the Division determined that the quarterly consumption limits are not necessary until the units start-up in combined cycle mode (turbine plus duct burner). In retrospect, the Division should not have allowed the increased natural gas consumption limit to take effect until startup of combined cycle operation commenced. However, since we did allow this and since the source has been subject to the higher limitation since February 2001, the Division believes it is unnecessary to require the short term fuel consumption limits. therefore, these limits will not be included in the permit.

• Emissions of air pollutants from the two turbines together shall not exceed the following limitations (condition 17):

Pollutant	Emission limit during the period (applicable for first twelve months of operation, beginning with the initial startup of combined cycle (turbine with duct burner) operation), tons			Emission limit, tons	
	June- August	September -November	December- February	March- May	Rolling 12 months
Particulate Matter	7.26	4.84	7.26	4.84	9.68
Particulate Matter < 10 µm [PM-10] (includes condensables)	7.26	4.84	7.26	4.84	9.68
Oxides of Nitrogen – until June 30, 2001.*					100.00
Oxides of Nitrogen – from July 1, 2001 until startup of combined cycle unit					83.33
Oxides of Nitrogen-upon startup of combined cycle unit	45.00	30.00	45.00	30.00	60.00
Carbon Monoxide					156.00
Carbon Monoxide – upon startup of combined cycle unit	90.00	60.00	90.00	60.00	120.00
Volatile Organic Compounds	16.78	11.19	16.78	11.19	22.38
Sulfur Dioxide	2.09	1.40	2.09	1.40	2.79

<sup>\*</sup>Note that the annual NO<sub>X</sub> limit that is effective until June 30, 2001 has not been included in the permit since it is no longer applies.

The construction permit was written to increase the PM,  $PM_{10}$ , VOC and  $SO_2$  emission limits to accommodate the increased fuel consumption and as discussed under the fuel consumption limits we probably should not have allowed the increase in emissions until combined cycle operation commenced. However, since we did allow this and since the source has been subject to the higher limitations since February 2001, the Division believes it is unnecessary to require the short term emission limitations for PM,  $PM_{10}$ ,  $SO_2$  and VOC, therefore, these limitations will not be included in the permit. Note that since the lower  $NO_X$  and CO limitations do not apply until combined cycle operation commences, the short term limitations still apply for these pollutants and will be included in the permit. In addition, since combined cycle operation began on May 1, 2002, the

Division included the May 1, 2002 date in the permit.

- Source compliance tests shall be conducted to measure the emission rates for the pollutants listed below (condition 18):
  - o particulate matter (to demonstrate compliance with the NSPS Subpart Da limits).

Note that the previous version of the construction permit included a requirement to determine a correlation between the emissions of VOC and other pollutants (CO and NO<sub>X</sub>). However, the performance testing for VOC indicated non-detectable VOC emissions, therefore, the requirement to use a correlation to determine VOC emissions was not included in the revised construction permit. The source will be estimating VOC emissions based on AP-42 emission factors. It should be noted that based on the source's performance test for VOC, it is very conservative to use the AP-42 emission factor.

Note that although the construction permit indicates that source is only required to demonstrate compliance with the NSPS Da particulate matter emission limitation, the Division considers that the source should also demonstrate compliance with the annual PM and  $PM_{10}$  emission limitations and to verify the emission factors used to estimate annual PM and  $PM_{10}$  emissions. Therefore, the operating permit will require that BIV monitor compliance with the annual PM and  $PM_{10}$  emission limitations.

 Prior to scheduling of the tests, the applicant shall submit to the Division for approval an operating and maintenance plan for all control equipment and control practices and a proposed record keeping format that will outline how the applicant will maintain compliance on an ongoing basis with the requirements of this permit (condition 19).

Since the operating permit defines the periodic monitoring that will be used to monitor compliance with the permit conditions, it is not necessary for the source to submit a proposed record keeping plan that will outline how the source will maintain compliance with the requirements of this permit. However, the construction permit requires that the source identify parameters that indicate "good combustion practices" and include these relevant parameters and their optimal operating range in the required operation and maintenance plan (condition 7). Therefore, there will be a requirement in the permit to develop and maintain a plan and make the plan available to the Division upon request that indicates what defines "good combustion practices" and how "good combustion practices" will be followed.

 APEN reporting (condition 18 and Colorado Regulation No. 3, Part A Section II.C)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the

permit, condition 22.e.

Although not specifically identified in Colorado Construction Permit 98MR0727 PSD, the turbines and duct burners are subject to the following applicable requirements:

- Sulfur dioxide emissions shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)
- Both units are subject to the Acid Rain requirements as follows:
  - o Allocated SO<sub>2</sub> allowances are listed in 40 CFR Part 73.10(b), however, since these are new units, no allowances were allocated. SO<sub>2</sub> allowances must be obtained per 40 CFR Part 73 to cover SO<sub>2</sub> emissions for the particular calendar year.
  - o There are no  $NO_X$  emission limitations since these units are not coal-fired boilers.
  - o Acid rain permitting requirements per 40 CFR Part 72.
  - o Continuous emission monitoring requirements per 40 CFR Part 75.
  - o This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Finally, for the reasons discussed below, the Division is including a requirement in the operating permit to conduct post-construction  $PM_{10}$  monitoring (Reg 3, Part B, Section IV.D.3.a.(iv)) for one year.

The construction permit application for the original construction of the turbines was submitted in October 1998. As part of the processing of the original construction permit (issued May 25, 1999) for the turbines, a modeling analysis was conducted. The modeling analysis submitted in February 1999, addressed emissions from all five turbines located at the Brush Cogeneration Facility. This analysis modeled PM<sub>10</sub> emission rates from all five turbines ranging from 16.2 lbs/hr to 17.1 lbs/hr and predicted a maximum 24-hr PM<sub>10</sub> impact of 15.3 μg/m<sup>3</sup>, which exceeded the 10 µg/m<sup>3</sup> level and so post-construction PM<sub>10</sub> monitoring was required. In lieu of conducting post-construction PM<sub>10</sub> monitoring, the source submitted a revised modeling analysis in April 1999, that used lower PM<sub>10</sub> emission rates for four of the turbines. Brush 1 and 3 (CPP turbines) and Brush 4A and 4B were modeled at PM<sub>10</sub> emission rates of 2 lbs/hr, while Brush 2 (BCP turbine) remained at 16.5 lbs/hr. This modeling analysis predicted a maximum 24-hr PM<sub>10</sub> impact of 8.1 µg/m<sup>3</sup>, which was below the 10 µg/m<sup>3</sup> level and so postconstruction PM<sub>10</sub> monitoring was not required and was not included in the initial construction permit issued May 25, 1999.

Performance tests to determine  $PM_{10}$  emissions were conducted on Brush 1, 3, 4A and 4B. Brush 1 and 3 were tested on December 21 and 22, 1999 and results indicated that  $PM_{10}$  emission rates from these units were 3.7 and 2.8 lbs/hr, respectively. Brush 4A and 4B were tested on January 13 and 14, 2000 and results indicated that  $PM_{10}$  emission rates from these units were 8.7 and 4.3 lbs/hr, respectively. Testing of these turbines indicated that the emission rates of all four turbines exceeded the level of emissions used in the April 1999 modeling analysis.

The source submitted a modeling analysis to support the alternate BACT limits during startup and shutdown on July 2000. In this analysis, the source addressed the higher particulate matter emission rate for Brush 1, 3, 4A and 4B. In this analysis, the source indicated that Brush 1, 3, 4A and 4B would be permitted at  $PM_{10}$  emission rates of 5 lbs/hr and that Brush 2 would also be permitted at an emission rate of 5 lbs/hr. Based on this analysis, the facility wide  $PM_{10}$  emission rates in the July 200 analysis were not significantly different from the facility wide  $PM_{10}$  emission rates modeled in April 1999. Therefore, if lower  $PM_{10}$  emission limits were taken for Brush 2, no further modeling would be required and post-construction  $PM_{10}$  monitoring was not required.

However, as of this date, there has been no request submitted to reduce the permitted PM<sub>10</sub> emissions for Brush 2. In the Division's response to comments (dated February 27, 2002) on the draft operating permit, this issue was addressed. The Division requested that the source either submit an application to modify the permit for Brush 2 to reduce the PM<sub>10</sub> emissions  $\underline{or}$  to submit a modeling analysis using the correct PM<sub>10</sub> emission rates for Brush 1, 3, 4A and 4B that demonstrates a maximum 24-hr PM<sub>10</sub> impact less than 10 µg/m³, otherwise, the Division would include post-construction PM<sub>10</sub> monitoring in the operating permit as an applicable requirement. As of May 24, 2002 (beginning of EPA 45-day review period), no permit modification application has been submitted for Brush 2 and no further modeling analysis has been conducted. Therefore, the operating permit includes a requirement to conduct post-construction PM<sub>10</sub> monitoring.

# Streamlining of Applicable Requirements

## **Opacity**

The turbines, themselves (simple cycle mode) are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbines are also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit.

The turbines and duct burners (combined cycle mode) are subject to the opacity requirements mentioned above and are also subject to the NSPS opacity requirements. The NSPS opacity requirements are not applicable during periods

of startup, shutdown and malfunction in accordance with the requirement in 40 CFR Part 60 Subpart A § 60.11(c). The NSPS opacity requirements are more stringent than the Reg 1 30% requirements under all the specific operating conditions except startup but are less stringent than the state-only Reg 6 requirements. The Reg 1 (20%/30%) opacity requirements are more stringent than the NSPS requirements during startup, shutdown and malfunction. Again, since no one opacity requirement is more stringent than the others at all times, all four opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency

It should be noted that since these turbines and duct burners use natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

## <u>SO</u><sub>2</sub>

Only the Regulation No. 1, Regulation No. 6, Part B and NSPS Subpart Da (which only applies when the turbines operate in combined cycle mode with the duct burners) SO<sub>2</sub> requirements are in the same units and can therefore be compared for the purposes of streamlining.

The Regulation No. 1 and No. 6, Part B SO<sub>2</sub> standards are the same, 0.35 The Regulation No. 6, Part B requirement is a state-only lbs/mmBtu. requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B SO<sub>2</sub> requirements do not apply during periods of startup, shutdown and malfunction. Regulation No. 1 SO<sub>2</sub> requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The NSPS Subpart Da requirement of 0.2 lbs/mmBtu appears to be more stringent than the Regulation No. 1 requirement. However, the NSPS Da requirement is based on a 30-day rolling average and the Reg 1 requirement is on a 3-hour rolling average. It is likely that the Reg 1 limit could be violated without violating the NSPS Da requirement. Therefore, these requirements

cannot be adequately compared for stringency so both requirements will be included in the operating permit.

## <u>NO</u><sub>X</sub>

Since the NSPS Subpart GG and BACT concentration limits are in the same units, they can be compared for purposes of streamlining. The BACT concentration limits are applicable at all times. The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the SO<sub>2</sub> streamlining section above). Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, even with the alternate BACT limit for startup and shutdown, the NSPS Subpart GG limits will be streamlined out of the operating permit.

Note that streamlined conditions are subsumed within the requirements identified in Section II of the permit. For purposes of compliance demonstration, compliance with the conditions in Section II of the permit also serve as compliance demonstration for the subsumed condition. Since the NSPS GG NO $_{\rm X}$  limit has been streamlined out in favor of the BACT NO $_{\rm X}$  limits, the source may wish to retain records of ambient temperature and humidity data which is used to convert NO $_{\rm X}$  values to ISO standard day conditions, in the event that the NO $_{\rm X}$  BACT limit is violated at such a level that compliance with the NSPS GG BACT limit is uncertain.

The duct burner is subject to an NSPS Subpart Da  $NO_X$  limit of 1.6 lbs/MW-hr gross energy output, on a 30-day rolling average, which cannot be compared with the BACT  $NO_X$  concentration limit (in ppmvd @ 15%  $O_2$ , on an hourly average), therefore, both requirements will be included in the permit.

#### PM

When the units are operating in combined cycle mode (turbine and duct burner), the units are subject to a Reg 1 particulate matter standard and the NSPS Da particulate matter standard. Although the NSPS Da particulate matter standards appear to be more stringent (0.03 lbs/mmBtu vs ~ 0.1 lbs/mmBtu), neither requirement can be streamlined out of the permit for the following reason: the NSPS Da requirement does not apply during periods of startup, shutdown and malfunction, as specifically stated in § 60.46a(c), but the Reg 1 particulate matter standard applies at all times. Therefore, during certain periods (i.e. startup, shutdown and malfunction), the Reg 1 particulate matter standard is more stringent. Therefore, both the Reg 1 and the NSPS Da particulate matter standards are included in the operating permit.

## Monitoring Requirements

These sources are subject to several types of monitoring requirements. The construction permit requires that the turbines be equipped with continuous emission monitors to monitor and record  $NO_X$  and CO emissions and the construction permit requires that these monitors be installed, maintained, calibrated and operated according to 40 CFR Part 60, Appendix F, although a

NO<sub>X</sub> monitor that meets the requirements in 40 CFR Part 75 may be used. Both turbines are subject to the Acid Rain requirements and as such are required to monitor emissions in accordance with the requirements in 40 CFR Part 75. When operating as combined cycle units, NSPS Da requires that a continuous emission monitor for NO<sub>X</sub> and either CO<sub>2</sub> or O<sub>2</sub> (diluent monitor) be installed and operated, although NSPS Subpart Da specifies in § 60.47a(c)(2) that a Part 75 NO<sub>X</sub> monitor may be used to satisfy the NO<sub>X</sub> continuous emission monitoring requirement. Upon initial startup these units were equipped with Part 60 monitors. A compliance order on consent (COC) was issued December 10, 2001 because these units were out of compliance with the Part 75 monitoring requirements. The COC required these units to come into compliance with the Part 75 monitoring requirements. In March 2001, the source submitted their Part 75 continuous emission monitoring certification package to EPA. source has installed Part 75 NO<sub>x</sub> (and diluent) monitors, the permit will specify that the NO<sub>X</sub> (and diluent) monitors must meet the requirements in 40 CFR Part Since NSPS Subpart Da and the construction permit both specifically indicated that NO<sub>X</sub> (and diluent) monitors, meeting the requirements of 40 CFR Part 75, could be used to satisfy the NO<sub>x</sub> continuous emission monitoring requirements no streamlining is necessary. NSPS Da specifically states that a Part 75 NO<sub>x</sub> CEMS satisfies the monitoring requirements in 40 CFR Part 60 Subpart Da § 60.47a. Note that the Division presumes that the minimum data requirements and data replacement requirements in 40 CFR Part 60 Subpart Da §§ 60.47a(f) and (h) still apply to the Part 75 monitors, since the source is required to report on the minimum data requirements in 40 CFR Part 60 Subpart Da § 60.49a. It should also be noted that the 40 CFR Part 60 excess emission reporting requirements for NO<sub>x</sub> will remain in the permit as 40 CFR Part 75 does not contain any NO<sub>X</sub> excess emission reporting requirements.

NSPS Subpart GG requires daily sampling of fuel to determine the nitrogen and sulfur content of the fuel. In an August 14, 1987 memo, the EPA waived the fuel sampling requirements to determine the nitrogen content for pipeline quality natural gas. The Acid Rain requirements allow sources that burn natural gas to use an alternate monitoring method in lieu of a continuous emission monitor for SO<sub>2</sub>. These requirements are in 40 CFR Part 75, Appendix D. Specifically, this monitoring method requires the source to monitor fuel fed to the combustion turbine for every hour that it combusts fuel. The source may then either sample and analyze natural gas for sulfur content or they may use the default SO<sub>2</sub> emission factor to determine SO<sub>2</sub>. The default emission factor may be used if pipeline quality natural gas is burned. The Part 75 monitoring plan submitted by the source on April 13, 2001 indicated that pipeline quality natural gas is used as fuel. In order to use the pipeline quality natural gas default emission factor, the source must demonstrate using any of the methods in 40 CFR Part 75. Appendix D, Section 2.3.1.4 that the fuel has a hydrogen sulfide content of less than 0.3 grain/100 SCF. The source is using the default emission factor provided by Part 75 Appendix D for the purposes of determining SO<sub>2</sub> emissions. Therefore, the NSPS Subpart GG requirement to sample fuel daily for sulfur content will be streamlined out of the permit in favor of the Part 75 pipeline quality natural gas requirement. It should be noted that EPA determinations support the use of the "Optional Sulfur Dioxide Emissions Data Protocol for Gas-Fired and Oil-Fired Units" of Appendix D of 40 CFR Part 75 as a custom fuel monitoring schedule for SO<sub>2</sub> (March 13, 2000 letter from John Hepola to Daniel Ewan, re "Approval of Alternative Monitoring for NSPS Subpart GG Pine Bluff Energy, LLC – Pine Bluff Energy Center Pine Bluff, Arkansas Operating Air Permit # 1822-AOP-R0", Control Number 0000015, from EPA Region 6).

The source is also required by 40 CFR Part 60 Subpart GG to continuously monitor the fuel consumption and the ratio of water to fuel being fired in the turbine (40 CFR Part 60 § 60.334(a)). The Division will streamline out the NSPS GG monitoring of fuel and water to fuel ratio in favor of the continuous emission monitoring system, since the continuous emission monitoring system is more stringent. Note that there are several EPA determinations indicating that it is acceptable to use a continuous emission monitoring system in favor of the NSPS GG required monitoring.

The construction permit requires that the continuous emission monitoring system be capable of monitoring the exhaust gas flow rate and the load at which both the turbine and the duct burner are operating. With the addition of the duct burners, the requirements in 40 CFR Part 60 Subpart Da became applicable requirements. 40 CFR Part 60 Subpart Da contains requirements to monitor exhaust gas flow and gross energy output. Although technically only the duct burner is subject to the requirements in 40 CFR Part 60 Subpart Da, it is not feasible to run the duct burner without running the turbine and 40 CFR Part 60 Subpart Da allows compliance with the NO<sub>x</sub> limitation for the duct burner to be monitored using a continuous emission monitor on the heat recovery steam generator stack, even though the stack includes emissions from the turbine. In addition, the method for monitoring compliance with the NO<sub>X</sub> limit, using the continuous emission monitoring system, allows for the gross energy output to be based on the gross energy output of the entire combined cycle unit (turbine plus duct burner). Therefore, the Division considers that the requirements in the construction permit to monitor exhaust gas flow rate and the load at which both the turbine and the duct burner are operating through a continuous monitoring system can be streamlined out in favor of the NSPS Da requirements to monitor gross energy output and exhaust flow rate, since the NSPS Da requirements are more specific and therefore more stringent.

**2. Emission Factors-** Emissions from these turbines are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO<sub>X</sub>), Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Particulate Matter (PM and PM $_{10}$ ). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency.

The emission factors that will be used to monitor compliance with the emission limits are as follows:

Pollutant	Emission Factor
PM	Unit 4A (GT-4) 0.0184 lbs/mmBtu Unit 4B (GT-5) 0.0087 lbs/mmBtu
PM <sub>10</sub>	Unit 4A (GT-4) 0.0184 lbs/mmBtu Unit 4B (GT-5) 0.0087 lbs/mmBtu
SO <sub>2</sub>	CMS
NO <sub>X</sub>	CEMS
СО	CEMS
VOC	0.0054 lbs/mmBtu

The VOC emission factor is from AP-42 (March 1998), Section 1.4 (natural gas fired boilers), Table 1.4-2, and represents emissions from the duct burner. The emission factor was converted to lbs/mmBtu by dividing by a heat content of 1,020 mmBtu/mmSCF as specified in AP-42. This emission factor is approved for use because it is more conservative than the AP-42 emission factor for gas turbines and the stack testing conducted on the turbines alone predict that the actual VOC emissions are below the AP-42 emission factor for turbines. Therefore, the boiler emission factor will conservatively predict emissions from the units in either simple or combined cycle operating mode.

The source proposed to use PM and  $PM_{10}$  emission factors from performance tests conducted January 13 and 14, 2000. They proposed the same emission factor for both turbines in units of lbs/mmSCF. The tests conducted in January 2000 indicated that Unit 4A (GT-4) had significantly higher emissions than unit 4B (GT-5) and since the performance test report did not provide information regarding the actual fuel flow rates to each unit during the test the Division was unable to determine whether the source's proposed emission factors were based on the test results for Unit 4A or 4B. Because of the discrepancy between the emissions from the two units, the Division would allow the source to use the higher emission factor for both units or to use separate emission factors for the turbines. A third option would be for the source to re-test the turbines, however, as of this date, the source has not re-tested either turbine. The Division included the emission factors from the test (in units of lbs/mmBtu) in the operating permit. A separate emission factor is provided for each turbine.

 $NO_X$  and CO emissions shall be determined using the continuous emission monitoring system required by the construction permit.  $SO_2$  emissions shall be determined using monitoring methods required by 40 CFR Part 75, Appendix D.

3. Monitoring Plan- The source shall be required to monitor compliance with the emission limits by monitoring fuel consumption and using emission factors based

on heat input. The source shall be required to record fuel consumption and calculate emissions monthly.

The continuous emission monitoring systems shall be used to monitor compliance with the BACT and annual  $NO_X$  and CO emission limitations. The NSPS Da  $NO_X$  limits for the duct burners shall be monitored using the continuous emission monitor. The monitoring methods required by 40 CFR Part 75, Appendix D shall be used to monitor compliance with the  $SO_2$  emission limitations.

The heat content of the natural gas shall be determined monthly through either sampling and analysis or use of vendor analyses. In the absence of credible evidence to the contrary, compliance with the opacity, particulate matter and Reg 1 SO<sub>2</sub> limits shall be presumed provided natural gas is used as fuel.

The source will be required to conduct a stack test to demonstrate compliance with the NSPS Subpart Da particulate matter standard and the annual particulate matter emission limitations and to verify the particulate matter emission factors within 180 days of startup of the units in combined cycle operation. In addition, the source will be required to conduct a performance test using the continuous emission monitoring system to determine compliance with the NSPS Da  $NO_X$  limit within 180 days of startup of the units in combined cycle mode.

**4. Compliance Status-** Current APENs reporting criteria and HAP emissions are on file with the Division. A revised permit was issued February 21, 2001 to allow these units to operate in combined cycle mode. Construction began shortly after the revised construction permit was issued. A COC was issued on December 10, 2001 because Brush 3 was out of compliance with the Acid Rain monitoring requirements (40 CFR Part 75). The COC requires the source to come into compliance with the Part 75 monitoring requirements. In March 2001, the source submitted their Part 75 continuous emission monitoring certification package to EPA.

# <u>Unit S006</u> - One (1) Marley Cooling Tower, Model No. W489-5.0-4, Rated at 68,500 gallons/min.

#### Discussion:

1. Applicable Requirements- The source indicated to the Division in a letter, dated June 30, 2000 that they intended to convert the turbines to combined cycle operation by adding heat recovery steam generators and duct burners and that to support the combined cycle operation a cooling tower would also be built. The application to modify the turbines to operate as combined cycle units was submitted on August 14, 2000 but did not include any information on a cooling tower. The source provided information on the cooling tower in their December 19, 2001 comments on the draft operating permit. The appropriate applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The applicable requirements for the cooling tower are as follows:

Visible emissions shall not exceed twenty percent (20%) opacity.

Based on engineering judgement, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no "startup" involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with this unit.

- Circulating water shall not exceed 16,440 mmgal per year (based on information submitted in the source's December 19, 2001 submittal indicating 4000 hrs/yr of operation for the cooling tower at the design rate of 68,500 gal/min)
- Emissions of air pollutants shall not exceed the following limitations (as indicated in the APEN submitted December 19, 2001):

o Particulate Matter (PM) 6.87 tons/yr

o Particulate Matter < 10Fm (PM<sub>10</sub>) 6.87 tons/yr

- APEN reporting in accordance with Regulation No. 3, Part A.II.C.
- Permit conditions for the cooling tower shall expire if construction does not commence within 18 months of issuance of the combined construction/operating permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time of the estimated completion date (Reg 3, Part B, Section IV.G.4.a.(i) (iii)). An extension of the 18 month construction period may be granted provided good cause is shown, an extension may not exceed 18 months (Reg 3, Part B, Section IV.G.4.b).
- The permittee shall notify the Division 30 days prior to startup of each unit (Reg 3, Part B, Section IV.H.1).
- Within 180 calendar days after startup, the source shall certify compliance with the terms and conditions for these units (Reg 3, Part B, Section IV.H.2).
- **2. Emission Factors-** Since cooling towers provide direct contact between the cooling water and the air passing through the tower, some liquid can be entrained in the air stream and emitted as "drift" droplets. Particulate matter contained in the "drift" is considered an emission as well as any chlorine or chloroform (VOC) from water treatment chemicals used in the cooling tower. The APEN submitted on December 19, 2001 indicated that VOC emissions were below APEN de minimis levels. Approval of emission factors for this unit is necessary to verify compliance with the emission limits. The source proposed to

calculate emissions from the cooling tower in the following manner:

PM = PM<sub>10</sub> = (water flow, gpm) x (water density, lbs/gal) x (% drift) x (31.3% PM/PM<sub>10</sub> from drift) x (total solids concentration, ppm)

Where: % drift = 0.02% (based on AP-42, Section 13,4, dated 1/95, Table 13.4-1)

31.3% PM from drift - from EPA-600/7-79-251a, November 1979, "Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume

1, Technical Report", page 63

- Monitoring Plan- The source shall be required to monitor the circulation rate of the water in the cooling tower and calculate emissions on a monthly basis. The water circulation rate is determined by the number of hours the tower has operated multiplied by the maximum capacity of the recirculating pump. Since the cooling tower only runs when the steam turbine runs, the hours of operation for the cooling tower will be based on the hours of operation metered on the steam turbine. In addition, particulate matter emissions are based on the total solids concentration in the cooling tower, therefore, the source will be required to sample and analyze circulating water to determine the total solids concentration of the circulating water. In lieu of sampling the circulating water to determine the total solids concentration, the source will measure the specific conductivity of the circulating water and multiply that number by 0.67. In the absence of credible evidence to the contrary, compliance with the opacity requirement will be presumed provided the cooling tower and associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.
- **4. Compliance Status-** An APEN was submitted for this unit on December 19, 2001. The applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. Since operation of the turbines in combined cycle mode occurred on May 1, 2002, it is likely that the cooling tower commenced operation on this date, although no permit was issued for this unit. Upon issuance of the operating permit, the source will be in compliance with the requirement to have a permit for this unit. Since the source has requested that the annual compliance period for the operating permit end on March 31, 2002, the first semi-annual monitoring period ends less than 180 days after the presumed startup of the cooling tower. Therefore, the first annual compliance certification submitted after the cooling tower commenced operation will serve as the self-certification that the cooling tower can comply with the permit conditions.

# IV. Compliance Assurance Monitoring (CAM) Requirements

The turbines are equipped with steam and enhanced water injection to control  $NO_X$  emissions. The turbines are subject to hourly  $NO_X$  BACT emission limits and annual  $NO_X$  emission limits. Note that the turbines are also subject to an NSPS GG  $NO_X$  limit, although the NSPS  $NO_X$  requirement has been subsumed within the hourly  $NO_X$  BACT limit. The initial construction permit for these turbines was issued on May 25, 1999 with  $NO_X$  limitations of 100 tons/yr, although the permit specified that within 24 months the  $NO_X$  limits would be

reduced to 83.3 tons/yr. The construction permit was revised on February 21, 2001 to convert the turbines to combined cycle operation, which adds a heat recovery steam generator and duct burner to each turbine. A subsequent reduction in  $NO_X$  emissions (to 60 tons/yr) takes effect upon startup of either unit in combined cycle operation. The duct burner itself is not equipped with a control device and by itself, is subject to an NSPS Da  $NO_X$  limitation. The turbine and duct burner combination is subject to hourly BACT  $NO_X$  emissions limits and annual  $NO_X$  emission limits.

As discussed previously, the BIV turbines, CPP turbines and BCP turbine comprise one single stationary source. As of January 1995, the CPP and BCP turbines were existing units subject to the Title V operating permit program and the Title V permit applications were submitted on February 23, 1996. The Title V permit application for the BIV turbine was submitted on April 27, 2000. Since the BIV turbines were large pollutant specific emission units (i.e. potential to emit, including controls, at major source levels) upon initial issuance of the construction permit and since the Title V permit application for the BIV turbines was not considered complete prior to April 20, 1998, in accordance with the provisions of 40 CFR Part 64 § 64.5(a)(1)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, the BIV turbines are subject to the compliance assurance monitoring (CAM) requirements. A CAM plan was not submitted by the source with their Title V permit application and a CAM plan has not been submitted as of the date of this document. However, since the turbines and turbine/duct burner combination are required to have NO<sub>X</sub> CEMS pursuant to the Acid Rain Program and the construction permit, the NO<sub>X</sub> CEMS shall be used to satisfy the CAM requirements as required by 40 CFR Part 64 § 64.3(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C. Section XIV. Therefore, the appropriate CAM requirements have been included in the operating permit.

The Division considers that the CAM requirements apply to the hourly BACT  $NO_X$  limits and the annual  $NO_X$  limits. The Division does not consider that the CAM requirements apply to the NSPS Da  $NO_X$  limit, since this requirement applies to the duct burners only and the duct burners are not equipped with a control device to reduce  $NO_X$  emissions.

## IV. Insignificant Activities

General categories of insignificant activities at this site include: chemical storage tanks/containers < 500 gal or storage areas < 5,000 gal, landscaping and site housekeeping equipment (< 10 hp), storage of butane, propane or NGL (vessels < 60,000 gal), lube oil storage tanks (< 40,000 gal), fuel (gaseous) burning equipment < 10 mmBtu/hr (for heating), an stationary internal combustion engines (limited size and hours of operation). The following list of insignificant activities was provided by the source in their comments on the draft permit received December 19, 2001:

Eight (8) water treatment chemical storage and dispensing tanks (125 gal each)

- Ten (10) small propane gas tanks, used for portable heaters and lights
- Ten (10) gas unit heaters and duct gas heaters (each at 125 mmBtu/hr)
- One (1) portable gasoline powered air compressor
- One (1) portable welding unit
- One (1) portable power generator

## V. Alternative Operating Scenarios

No alternative operating scenarios were requested for this facility.

#### VI. Permit Shield

The source requested the permit shield for those requirements it identified as applicable to the emission unit. There are two permit shields that can be obtained for the Operating Permit. In general, the permit shield applies to the applicable requirements and states that compliance with the Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the Operating Permit. If the source specifically requests and provides a justification, it can be shielded from requirements that are not applicable to the facility or to an emission unit. In their initial Title V permit application, the source did not request the permit shield for any non-applicable requirements. However, in their comments submitted during the Public Comment period, the source indicated that they would like the permit shield for the requirements in 40 CFR Part 63 Subpart Q, as adopted by reference in Colorado Regulation No. 8, Part E, "National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers". The source indicated that these requirements were not applicable since the cooling tower would not be using chromium-based chemicals. The permit shield was granted based on the source's justification.

The following applicable requirements were streamlined out of the permit and have been included in the permit shield.

- **State-only** 0.35 lbs/mmBtu SO<sub>2</sub> requirement (Reg 6, Part B, Section II.D.3.b), streamlined out since Reg 1 SO<sub>2</sub> requirement is more stringent.
- 75 ppmvd NO<sub>X</sub> at 15% O<sub>2</sub> requirement for the turbines (Colorado Construction Permit 98MR0727 PSD and 40 CFR Part 60 Subpart GG § 60.334(b), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the NO<sub>X</sub> BACT limit (30/25 ppmvd at 15% O<sub>2</sub>) is more stringent. Note this also includes the exemptions from the standard in 40 CFR Part 60 Subpart GG §§ 60. 60.332(f) & (i).
- Continuous monitoring system requirement to monitor and record the fuel consumption rate and the ratio of water to fuel being fired in the turbine (40 CFR Part 60 Subpart GG § 60.334(a), streamlined out in favor of the more stringent continuous emission monitoring requirements.
- Monitor sulfur and nitrogen content of fuel (40 CFR Part 60 Subpart GG § 60.334(b)) and test methods and procedures for fuel sampling (40 CFR Part 60 Subpart GG §§ 60.335(d) & (e)), streamlined out in favor of the

- continuous emission monitor (nitrogen sampling) and the Acid Rain requirement for pipeline quality natural gas (sulfur sampling).
- Excess emission reporting for any one-hour period during which the average water-to fuel ratio is less that the ratio determined by the performance test and/or any period nitrogen content is greater than that used in the performance test (40 CFR Part 60 Subpart GG § 60.334(c)(1)), streamlined out in favor of reporting excess NO<sub>X</sub> emissions determined by the continuous emission monitoring system.
- Excess emission reporting for any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 % (40 CFR Part 60 Subpart GG § 60.334(c)(2)), streamlined out in favor of the Acid Rain requirement for pipeline quality natural gas.
- Requirement to record the exhaust gas flow rate on the continuous monitoring system, or parametrically, (Colorado Construction Permit 98MR0727 PSD, Condition 8.a), streamlined out in favor of the requirement to record exhaust gas flow in 40 CFR Part 60 Subpart Da §§60.47a(I), (m), or (n).
- Requirement to record the load at which the turbine and duct burner are operating at on the continuous monitoring system (Colorado Construction Permit 98MR0727 PSD, Condition 8.f), streamlined out in favor of the requirement to record gross energy load in 40 CFR Part 60 Subpart Da § 60.47a(k).

## VII. Acid Rain Provisions:

Both turbines and duct burners are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit. Units subject to the Acid Rain requirements are required to hold adequate  $SO_2$  allowances and have  $NO_X$  limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain  $SO_2$  allowances as needed. Since these units are not coal-fired boilers, they do not have any  $NO_X$  limitations under the Acid Rain Program.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of  $SO_2$ ,  $NO_X$  (with diluent monitor either  $CO_2$  or  $O_2$ ) and  $CO_2$  as well as opacity and volumetric flow in accordance with the requirements in 40 CFR Part 75. Since these units burn natural gas, these units are not required to have a continuous opacity monitor and can use an alternate monitoring method (Appendix D), in lieu of installing and operating a continuous emission monitor for  $SO_2$ .

In March 2001, the source submitted their Part 75 continuous emission monitoring certification package to EPA.